UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT PURSUANT TO
SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): December 6, 2016

LAREDO PETROLEUM, INC.

(Exact Name of Registrant as Specified in Charter)

Delaware	**001-35380**	**45-3007926**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 900, Tulsa, Oklahoma	**74119**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code: **(918) 513-4570**

Not Applicable
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01. Regulation FD Disclosure.

On December 6, 2016, Laredo Petroleum, Inc. (the "Company") posted to its website a Corporate Presentation (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached to this Current Report on Form 8-K as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

All statements in this Item 7.01 and the Presentation, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in the forward-looking statements. See the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and the Company's other filings with the SEC for a discussion of other risks and uncertainties. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In accordance with General Instruction B.2 of Form 8-K, the information furnished under this Item 7.01 of this Current Report on Form 8-K and the exhibit attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit Number	Description
99.1	Presentation dated December 6, 2016.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Dated: December 6, 2016

By: /s/ Kenneth E. Dornblaser

Kenneth E. Dornblaser

Senior Vice President and General Counsel

EXHIBIT INDEX

Exhibit Number	Description
99.1	Presentation dated December 6, 2016.

EXHIBIT 99.1

Forward-Looking / Cautionary Statements

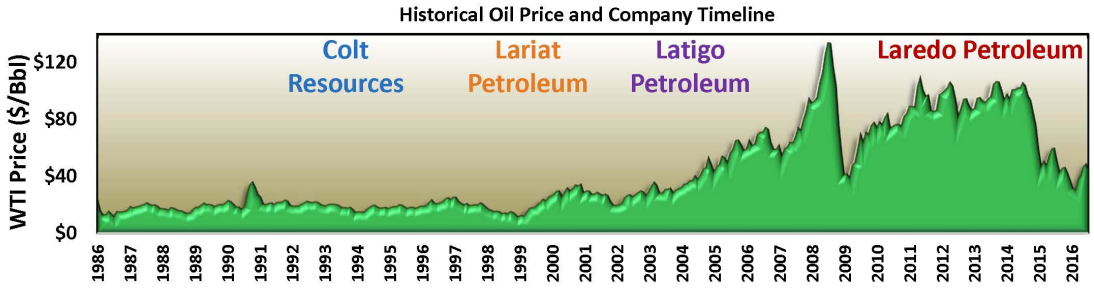
This presentation and all oral statements made in connection herewith contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "project," "intend," "indicator," "foresee," "forecast," "guidance," "should," "would," "could," "goal," "target," "suggest" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature and are not guarantees of future performance. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and other reports filed with the Securities Exchange Commission ("SEC").

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies to disclose proved reserves in filings made with the SEC, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "unproved reserves," "resource potential," "estimated ultimate recovery," "EUR," "development ready," "horizontal productivity confirmed," "horizontal productivity not confirmed" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. The Company does not choose to include unproved reserve estimates in its filings with the SEC. "Estimated ultimate recovery", or "EUR", refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provide additional data. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Led By Experienced Management Team

- Each member of the senior management team has more than 30 years of energy industry experience
- Randy Foutch has founded four successful exploration and production companies and operated through a range of oil price environments



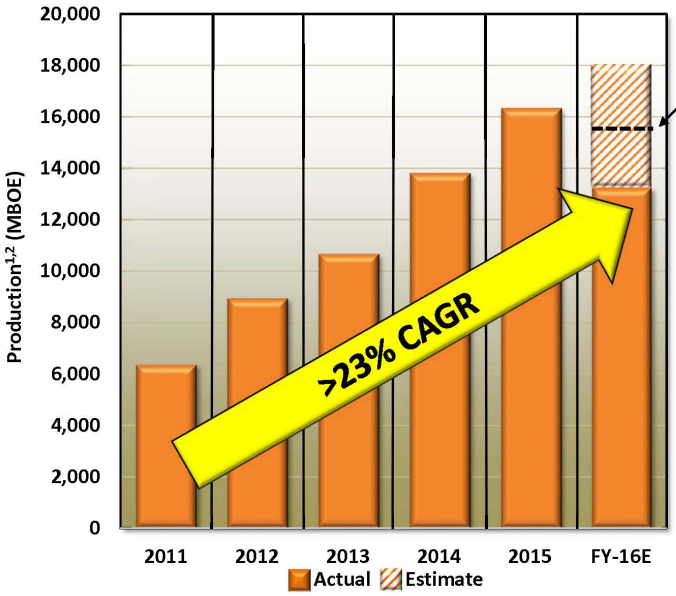
Prior Investments Creating Value

- **Multi-zone, contiguous acreage position enabling development efficiencies**
  - Year-to-date average completed lateral length of ~10,000' driving higher rates of return
- **Data powering the Multivariate Earth Model**
  - Multivariate Earth Model optimized drilling and completions have yielded well results averaging ~39% higher than 1+ MM BOE type curves
- **Production corridors lowering operating and capital costs**
  - Production corridors benefited LOE ~$0.67/BOE in the first nine months of 2016
  - 10,000' UWC and MWC drilling and completions costs decreased ~$2 MM in 2016
- **Medallion-Midland Basin Pipeline System growing transported volumes**
  - Medallion-Midland Basin Pipeline is expected to double delivered volumes in 2016 and grow 50% - 60% in 2017

Prior strategic investments and continuous performance improvements yield repeatable benefits

Consistent Production Growth

Anticipated 2016 production growth of ~10%



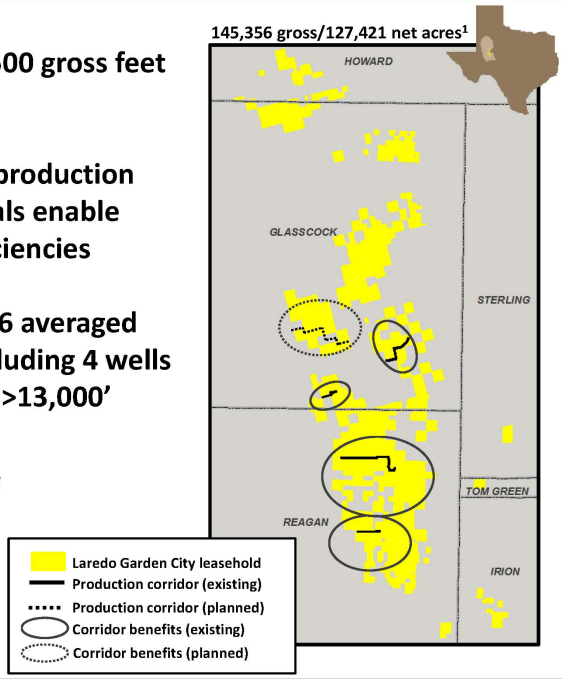
- Anticipate full-year 2016 production growth of ~10% YoY
- Production guidance increases attributable to
  - Multivariate Earth Model optimized drilling and completions
  - Infrastructure benefits
  - Drilling efficiencies

[1] Production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 results have been converted to 3-stream using actual gas plant economics
[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013

Capitalizing on Contiguous Acreage Position

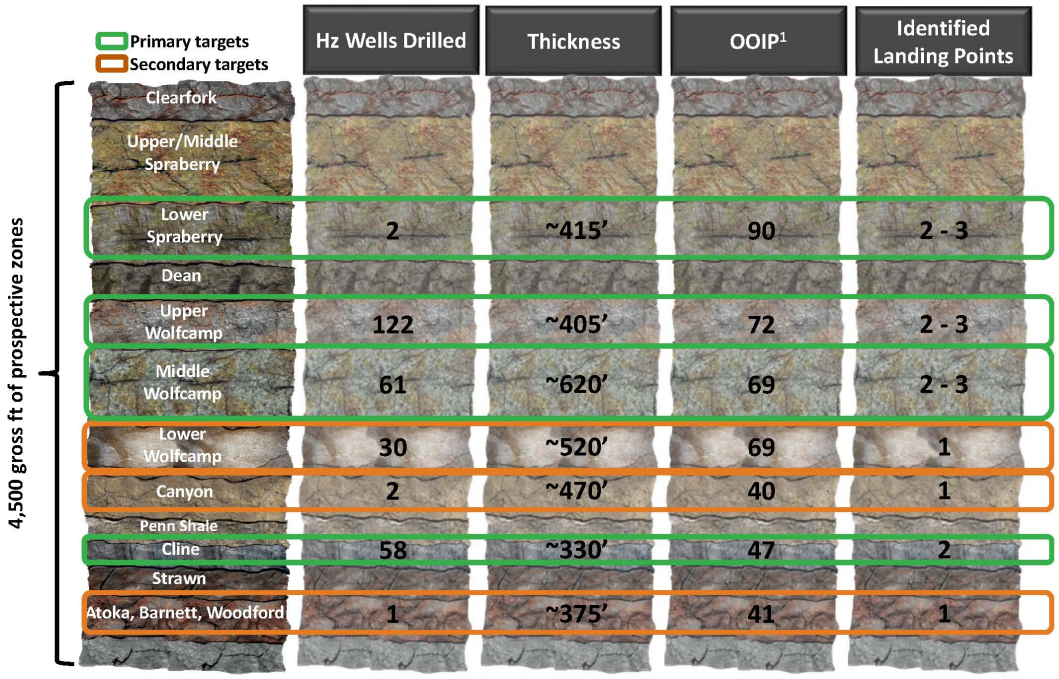
- Contiguous acreage position with ~4,500 gross feet of prospective zones
- Centralized infrastructure in multiple production corridors and ability to drill long laterals enable increased capital and operational efficiencies
- 10 horizontal wells completed in 3Q-16 averaged >10,900' completed lateral length, including 4 wells each drilled with a total lateral length >13,000'

>80% of acreage HBP, enabling a concentrated development plan along production corridors[1]



[1] As of 9/30/16

Multiple Targeted Horizons

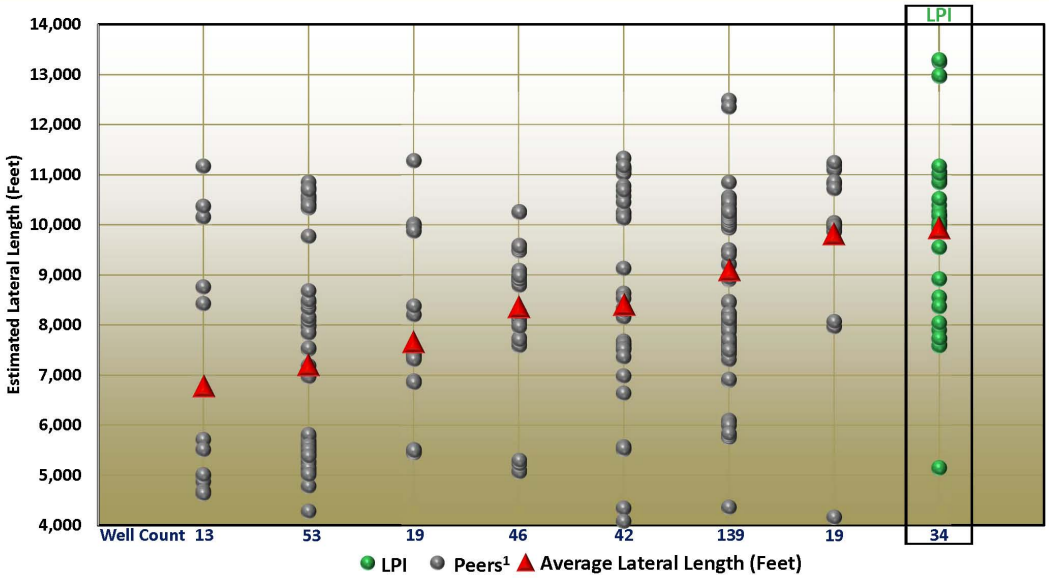


	Hz Wells Drilled	Thickness	OOIP[1]	Identified Landing Points
Lower Spraberry	2	~415'	90	2 - 3
Upper Wolfcamp	122	~405'	72	2 - 3
Middle Wolfcamp	61	~620'	69	2 - 3
Lower Wolfcamp	30	~520'	69	1
Canyon	2	~470'	40	1
Cline	58	~330'	47	2
Atoka, Barnett, Woodford	1	~375'	41	1

[1] Representative of the estimated mean original oil in place (OOIP) per section, measured in stock tank million barrels of oil equivalent

LAREDO PETROLEUM

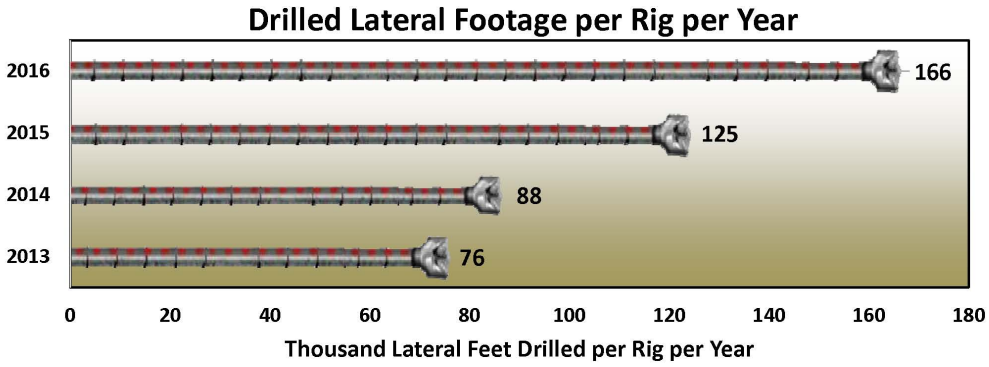
Contiguous Acreage Position Enables Drilling of Longer Laterals



Peer-leading, long-lateral execution

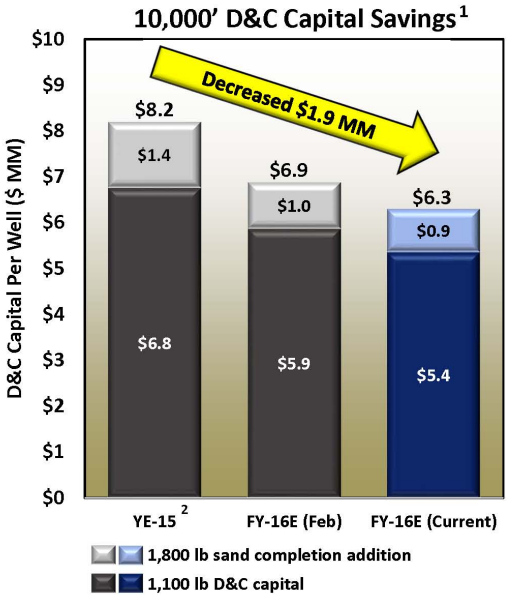
[1] Peers include: Callon, Diamondback, Encana, Energen, Parsley, Pioneer & RSP Permian; data includes 01/01/16 - 10/27/16 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX

Drilling Efficiencies Drive Lower Well Costs



Significant drilling efficiency improvements realized without material increases in capex per rig, improving capital efficiency

Decreasing D&C Costs



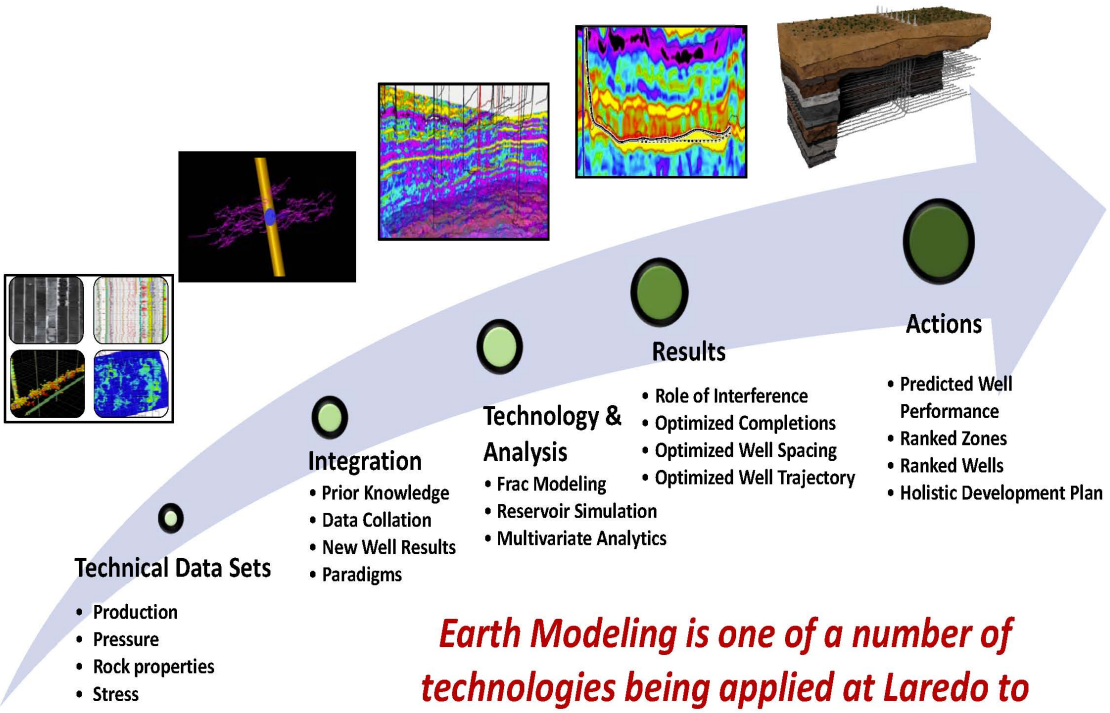
- **D&C costs for recent Upper and Middle Wolfcamp wells have been in the mid $5 MM range**

- **D&C capital includes:**
  - Pad preparation
  - Well-site metering
  - Heater treaters
  - Separation equipment
  - Artificial lift equipment

23+% average D&C capital savings YTD in all zones

[1] Representative of 2-well pad costs
[2] YE-15 well cost estimates for FY-16

Laredo's Technology Workflow



Technical Data Sets
- Production
- Pressure
- Rock properties
- Stress

Integration
- Prior Knowledge
- Data Collation
- New Well Results
- Paradigms

Technology & Analysis
- Frac Modeling
- Reservoir Simulation
- Multivariate Analytics

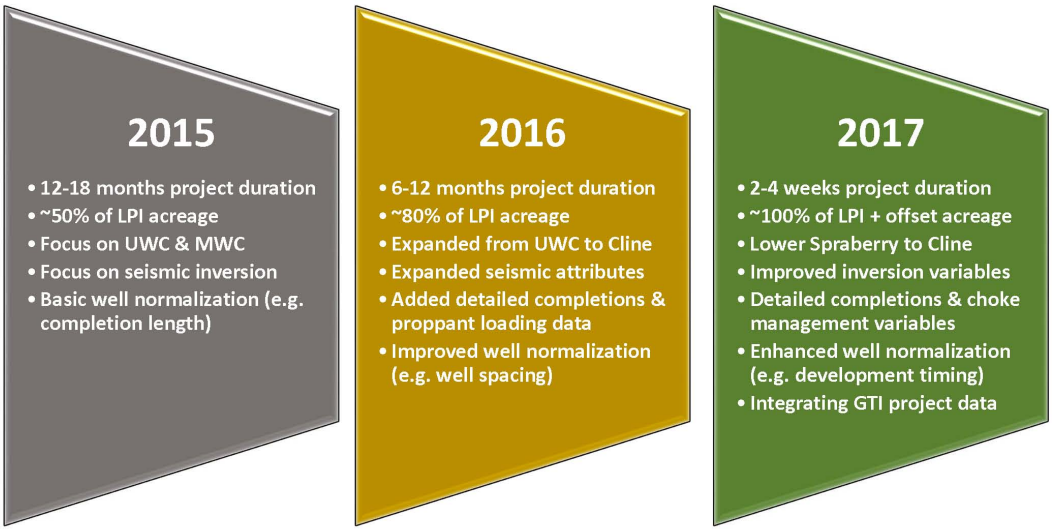
Results
- Role of Interference
- Optimized Completions
- Optimized Well Spacing
- Optimized Well Trajectory

Actions
- Predicted Well Performance
- Ranked Zones
- Ranked Wells
- Holistic Development Plan

Earth Modeling is one of a number of technologies being applied at Laredo to enhance shareholder value

Evolving Beyond the Earth Model

Enhanced analysis of key production drivers



Hydraulic Fracture Test Site (HFTS)

$23 MM high-profile, joint-industry project led by Laredo and the Gas Technology Institute (GTI)

Laredo's Project Contribution

- Selected as operator
- Conducted on Laredo's acreage
- No cost to Laredo
- On-time, on-budget
- Strong linkage to completions optimization

Site Host

LAREDO PETROLEUM

Research Team

gti · Bureau of Economic Geology · The University of Texas at Austin

Sponsors

U.S. Department of Energy · NETL · devon · HALLIBURTON · EnCana · TOTAL · ConocoPhillips · Core Lab · Discovery Natural Resources · Shell · ENERGEN

→ *In-Progress*
☑ *Complete*

Key Initiatives

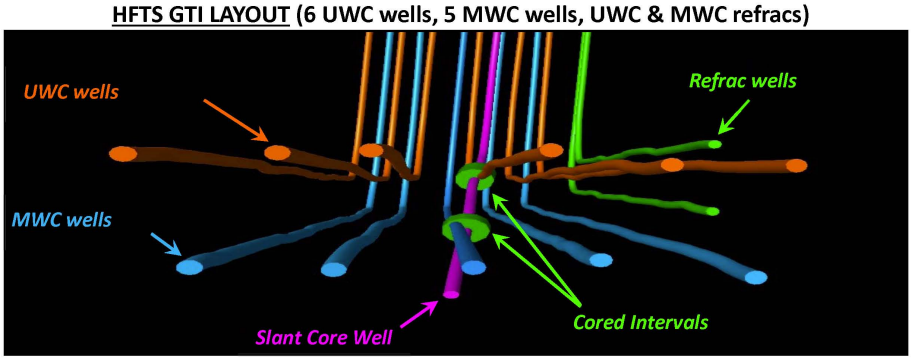
- → Slant Well Fracture & Proppant Analysis
- → Hydraulic Fracture Modeling
- → Fracture Attribute Studies

Data Sets Acquired

- ☑ Drilling, Coring & Logging Slant Well
- ☑ Pilot Hole Logs & Sidewall Cores
- ☑ Offset Well Refracs (μ-seismic & tracers)
- ☑ Horizontal DFIT's
- ☑ Radioactive Tracers & Fluid Tracers
- ☑ Microseismic Monitoring
- ☑ Cross-Well Seismic
- ☑ Surface Seismic Monitoring
- ☑ Colored Proppant Cluster Indicators
- ☑ Inter-well Pressure Monitoring
- ☑ Fiber Optic Production Logging
- ☑ Environmental Sampling
- ☑ Oil Fingerprinting / Fluid Sampling

Advanced Hydraulic Fracture Data Collected on Laredo Leasehold

HFTS GTI LAYOUT (6 UWC wells, 5 MWC wells, UWC & MWC refracs)



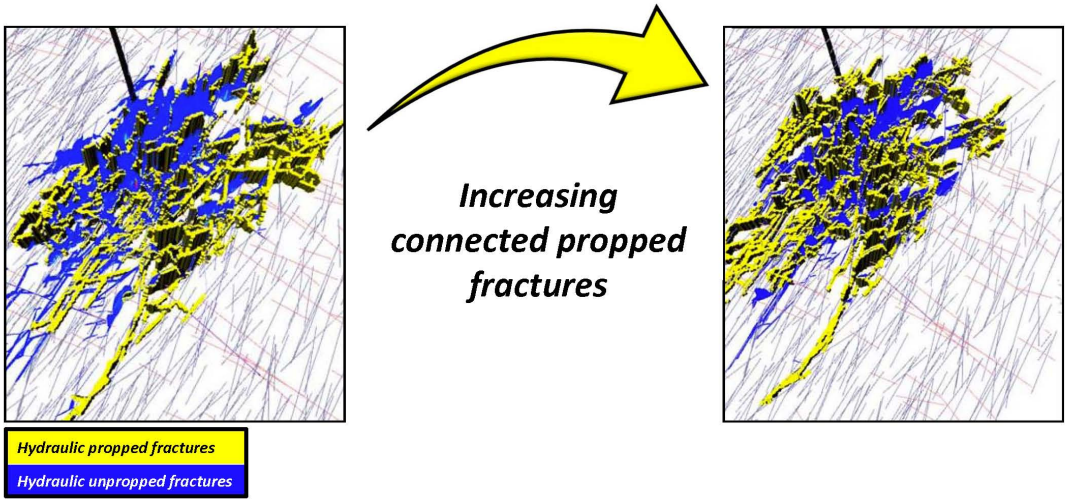
HYDRAULICALLY FRACTURED CORE

Recovered core showing complexity of hydraulically created fractures

- ~600 feet recovered
- UWC & MWC
- Natural fractures
- Hydraulic fractures
- Proppant recovered

Cutting-edge completions data being integrated into the multivariate Earth Model

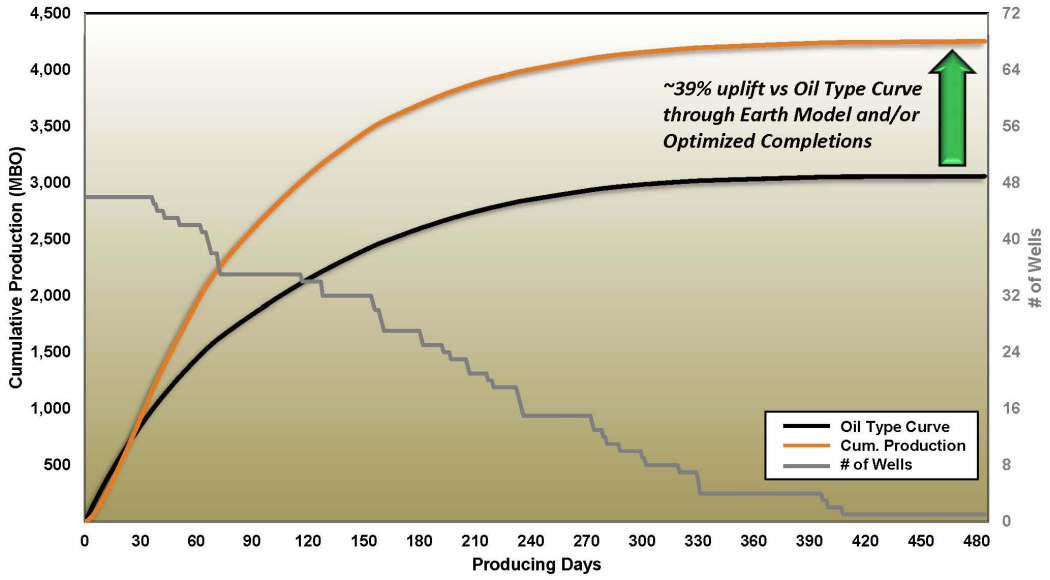
Advanced Fracture Modeling



Utilizing multivariate Earth Model analysis to optimize completions designs

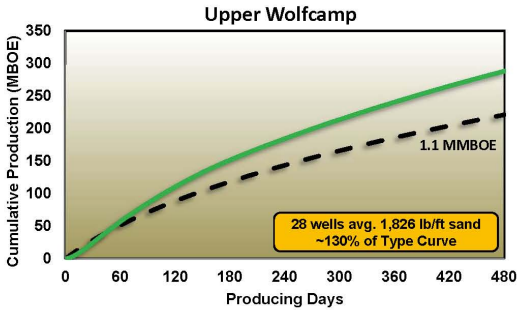
Earth Model and Completion Optimization Benefits

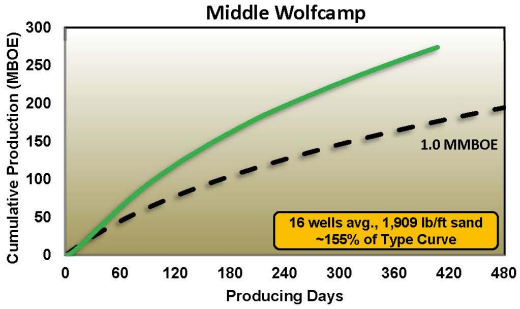
Wells utilizing the Earth Model and optimized completions have performed at an average of ~139% of Oil Type Curve[1]

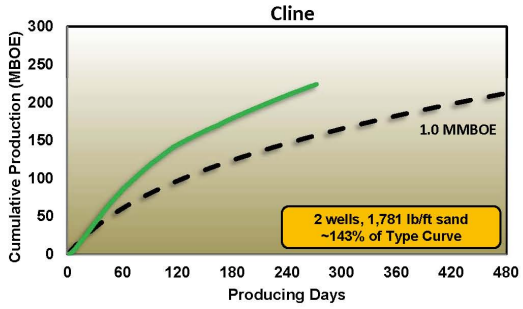


[1] Average cumulative production data through 12/3/16. 46 Hz wells have utilized both the Earth Model and optimized completions

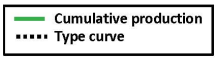
Multivariate Earth Model Enhancing Production







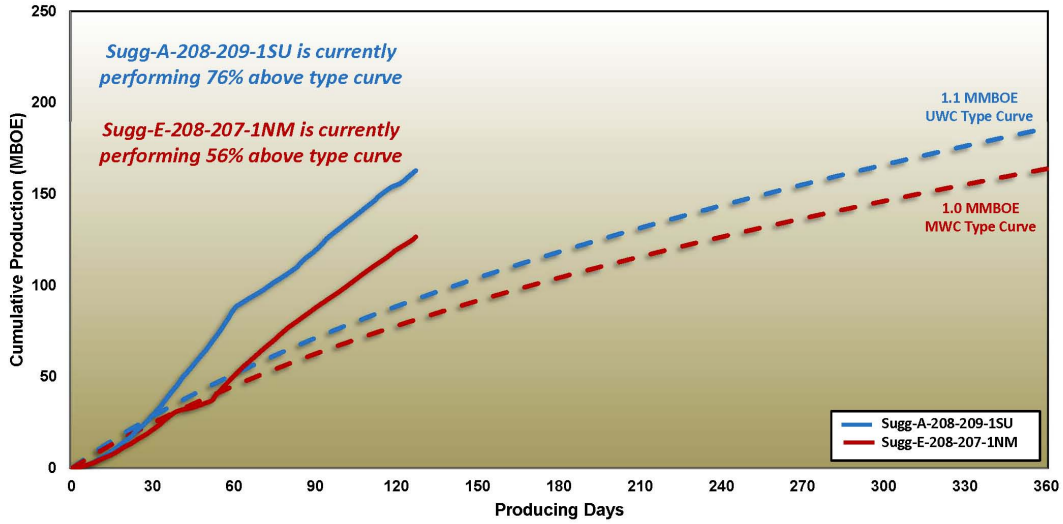
Wells drilled with the Multivariate Earth Model and optimized drilling and completions have resulted in significant outperformance versus the Company's type curves



Note: Average cumulative production data through 12/3/16. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

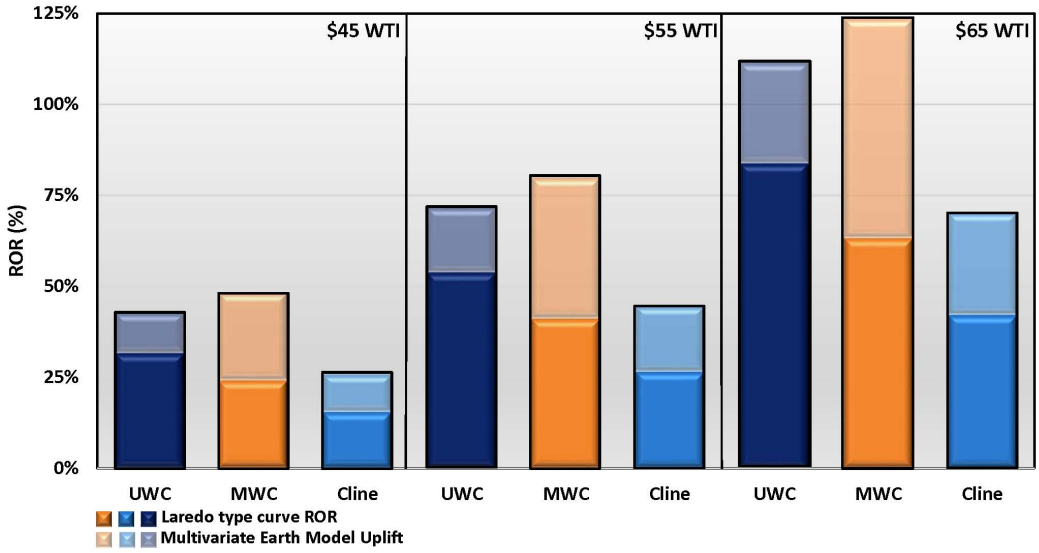
Latest Optimization Tests Significantly Exceeding Type Curve

Initial two wells utilizing the multivariate Earth Model and optimized drilling and completions with 2,400 lb/ft sand are yielding results significantly greater than type curve



Note: Includes the two 3Q-16 wells with 30 day peak initial production data; both wells were drilled utilizing the multivariate Earth Model drilling and optimized completions with ~2,400 lb/ft of sand. Production as of 12/3/2016 has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Multivariate Earth Model Driving Meaningful Uplift in Returns



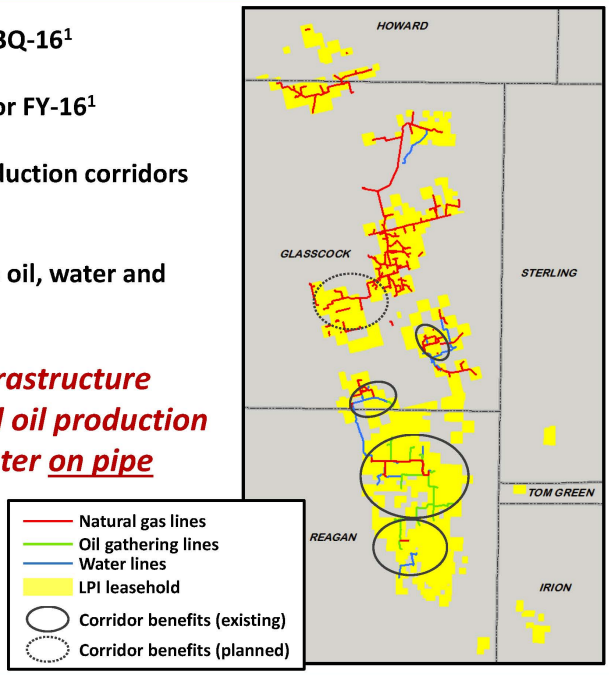
Demonstrated performance uplifts in each zone yield significant return improvements

Note: Rate of returns calculated using benchmark prices of WTI: $45.00/Bbl, $55.00/Bbl, $65.00/Bbl & HH: $3.00/Mcf, $3.25/Mcf, $3.50/Mcf and realized pricing of WTI: $39.23/Bbl, $47.95/Bbl, $56.67/Bbl & HH: $2.16/Mcf, $2.34/Mcf, $2.52/Mcf & NGLs: $11.58/Bbl, $14.15/Bbl, $16.72/Bbl

Prior Investment in Infrastructure Providing Tangible Benefits

- >$6.0 MM total realized benefits in 3Q-16[1]
- ~$25 MM total estimated benefits for FY-16[1]
- ~195 horizontal wells served by production corridors with potential for >2,500 more[2]
- Invested ~$150 MM to date in crude oil, water and natural gas midstream assets

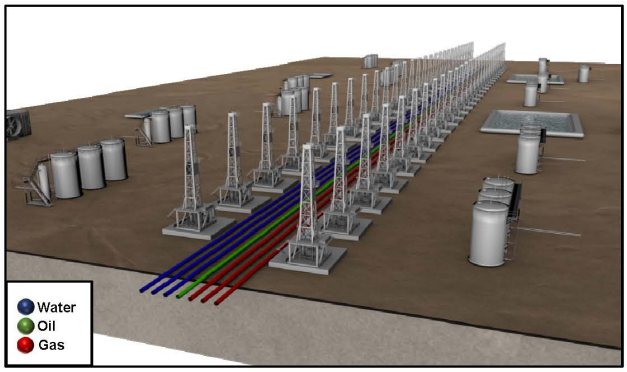
In 3Q-16, Laredo-owned infrastructure gathered 69% of gross operated oil production & 67% of total produced water on pipe



[1] Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income
[2] Includes planned Western Glasscock production corridor
Note: Infrastructure includes crude gathering/transportation, water gathering, distribution & recycle, natural gas gathering and centralized gas lift compression

Corridor Financial Benefits

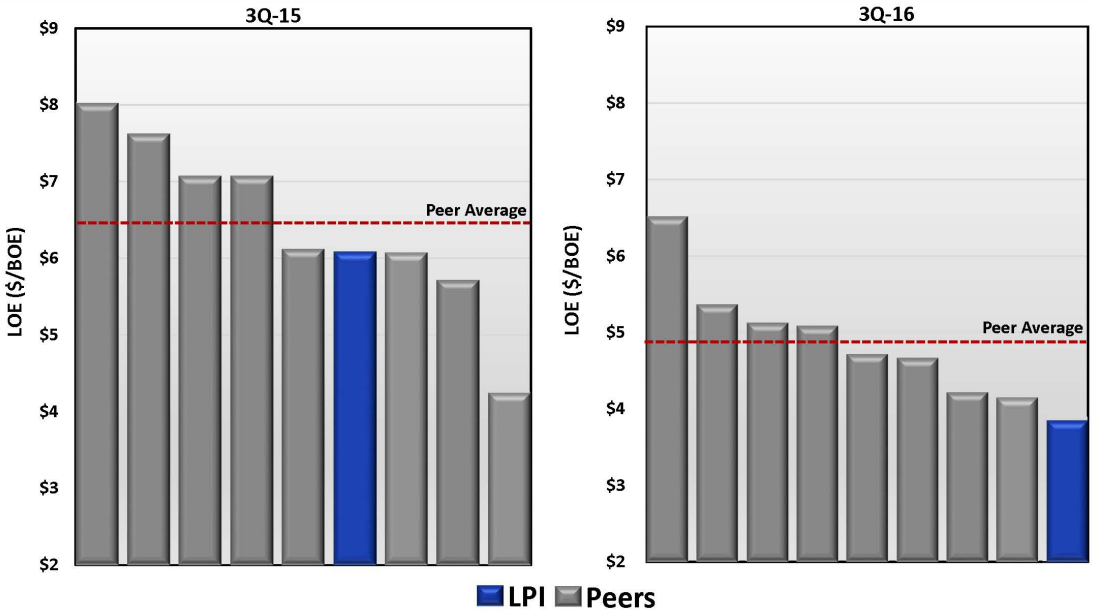
~$1.6 MM benefit over life of each 10,000' corridor well, with ~25% of the benefit received in the first six months[1]



LMS Service	3Q-16 Benefits Actual ($ MM)	2016 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$3.1	$11.4	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.2	$0.9	LOE savings
Frac Water (Recycled vs Fresh)	$0.4	$1.1	Capital savings
Produced Water (Recycled vs Disposed)	$0.4	$2.0	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$1.9	$9.3	Capital & LOE savings
Corridor Benefit	$6.0	$24.7	

[1] Benefits estimates as of October 27, 2016

Peer-Leading Unit LOE[1]



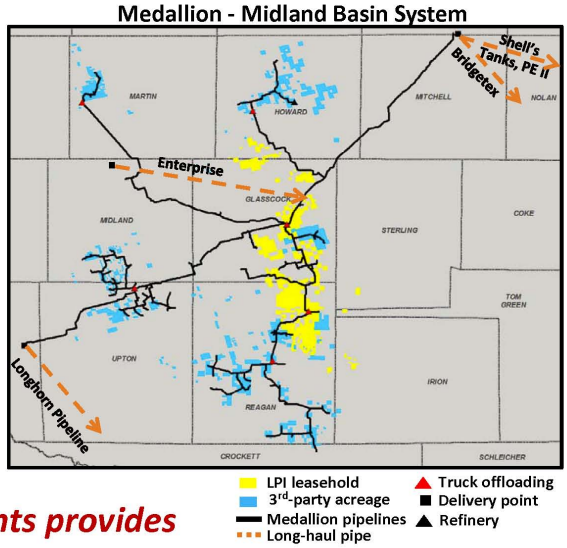
Production corridor assets reduced unit LOE ~$0.52/BOE in 3Q-16

[1] Peers are CPE, CXO, EGN, EPE, FANG, PE, PXD & RSPP. Two-stream reporters were converted to three-stream utilizing an 18% volume uplift

Medallion-Midland Basin Crude Oil System

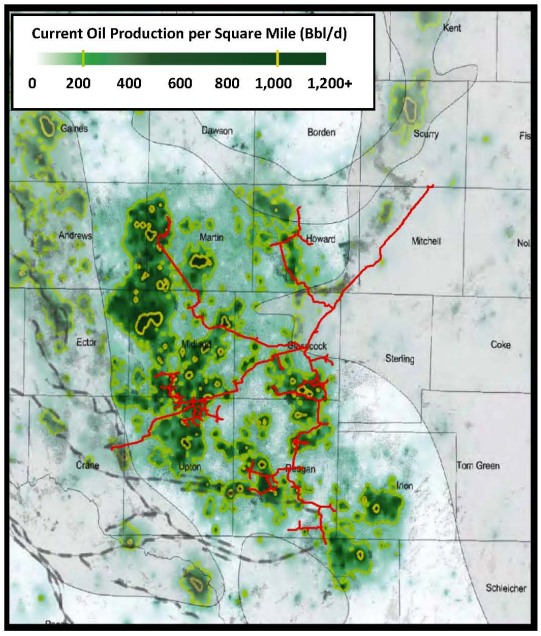
- ~500 miles with >325,000 net acres dedicated to system
- $0.48/Bbl 3Q-16 cash flow margin net to LPI
- YE-16 estimated exit rate of 140,000 BOPD
- ~2 MM acres either under AMI or supporting firm commitments

Medallion - Midland Basin System

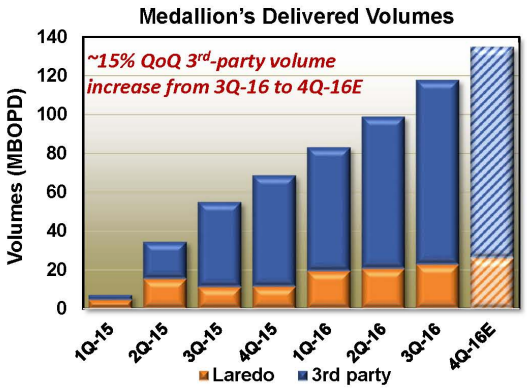


Access to multiple delivery points provides optionality to various crude markets, avoiding potential bottlenecks out of the Midland Basin

Medallion-Midland Basin: The Premier Pipeline in the Permian



— Medallion–Midland Basin pipelines

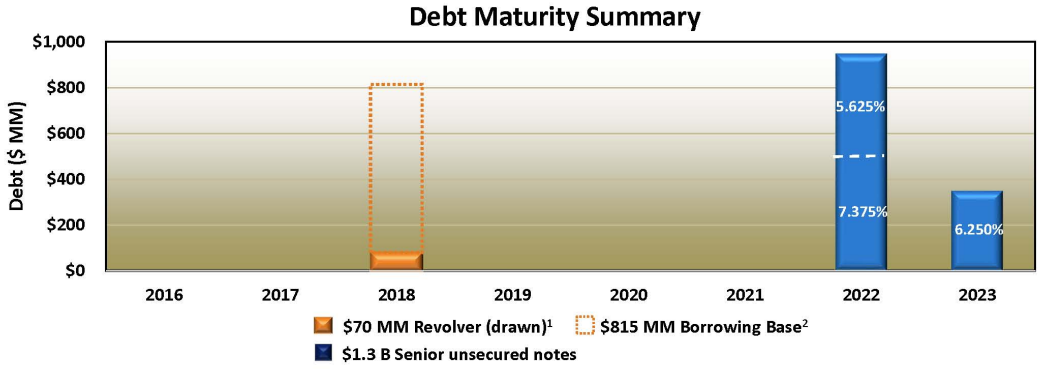


Access to the most productive parts of the Midland Basin drives significant growth on the Medallion-Midland Basin Pipeline

Note: Heat map generated by RS Energy Group

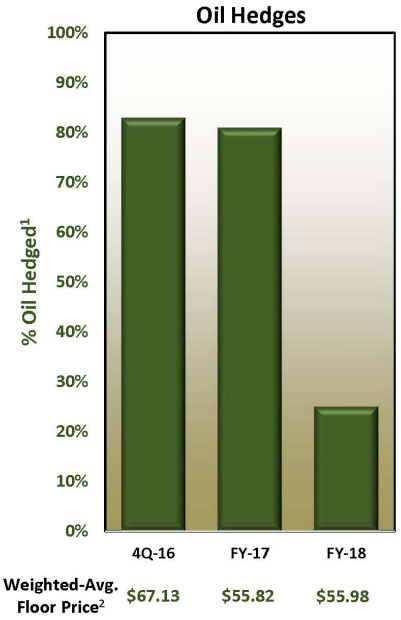
Strong Financial Position

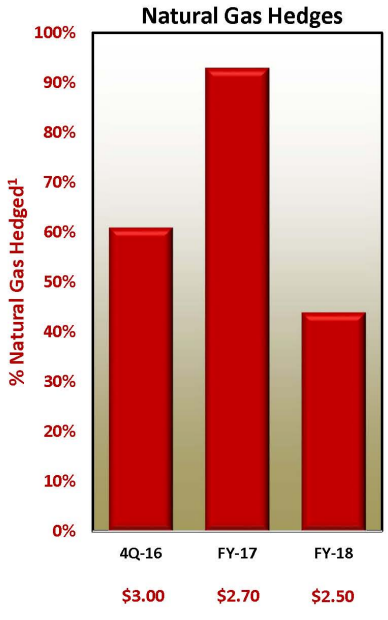
- ~$755 MM of liquidity[1]
- No term debt due until 2022
  - $950 million of notes callable at Laredo's option in 2017
- Top-tier, multi-year hedge position



[1] As of 11/01/16
[2] As of October 2016 redetermination; Medallion interest is not pledged to borrowing base

Top-Tier, Multi-Year Hedge Position





Hedging program provides price protection while retaining substantial upside

[1] Utilizing midpoint of current 2016 production for FY-17 and FY-18 percent hedged
[2] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil and natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period
Note: Does not include 2017 NGL hedges of 444,000 Bbl of ethane or 375,000 Bbl of propane

Fourth-Quarter 2016 Guidance

	4Q-2016
Production (MMBOE)	4.7 - 4.9
Product % of total production:	
Crude oil	45% - 47%
Natural gas liquids	26% - 27%
Natural gas	27% - 28%
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	~87%
Natural gas liquids (% of WTI)	~30%
Natural gas (% of Henry Hub)	~72%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.75 - $4.25
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$3.25 - $3.75
Noncash stock-based compensation ($/BOE)	$2.00 - $2.25
Depletion, depreciation and amortization ($/BOE)	$7.75 - $8.25


LAREDO
PETROLEUM
Appendix

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	4Q-16	2017	2018
Puts:			
Hedged volume (Bbls)	549,000	1,049,375	1,049,375
Weighted average price ($/Bbl)	$42.95	$60.00	$60.00
Swaps:			
Hedged volume (Bbls)	395,600	2,007,500	1,095,000
Weighted average price ($/Bbl)	$84.82	$51.54	$52.12
Collars:			
Hedged volume (Bbls)	916,750	3,796,000	
Weighted average floor price ($/Bbl)	$73.98	$56.92	
Weighted average ceiling price ($/Bbl)	$89.62	$86.00	
Total volume with a floor (Bbls)	1,861,350	6,852,875	2,144,375
Weighted-average floor price ($/Bbl)	$67.13	$55.82	$55.98

NATURAL GAS[2]			
Put			
Hedged volume (MMBtu)		8,040,000	8,220,000
Weighted average floor price ($/MMBtu)		$2.50	$2.50
Collars:			
Hedged volume (MMBtu)	4,692,000	19,016,500	4,635,500
Weighted average floor price ($/MMBtu)	$3.00	$2.86	$2.50
Weighted average ceiling price ($/MMBtu)	$5.60	$3.54	$3.60
Total volume with a floor (MMBtu)	4,692,000	27,056,500	12,855,500
Weighted-average floor price ($/MMBtu)	$3.00	$2.75	$2.50

NATURAL GAS LIQUIDS[3]			
Swaps - Ethane:			
Hedged volume (Bbls)		444,000	
Weighted average price ($/Bbl)		$11.24	
Swaps - Propane:			
Hedged volume (Bbls)		375,000	
Weighted average price ($/Bbl)		$22.26	
Total volume with a floor (Bbls)		819,000	

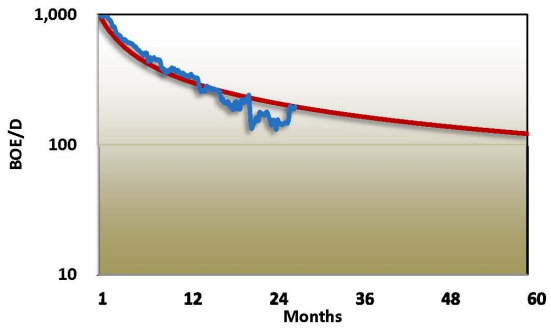
Note: Open positions as of 09/30/16, including hedges placed through 12/05/16

[1] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil

[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period

[3] Natural gas liquids derivatives are settled based on the month's daily average of OPIS Mt. Belvieu Purity Ethane and TET Propane

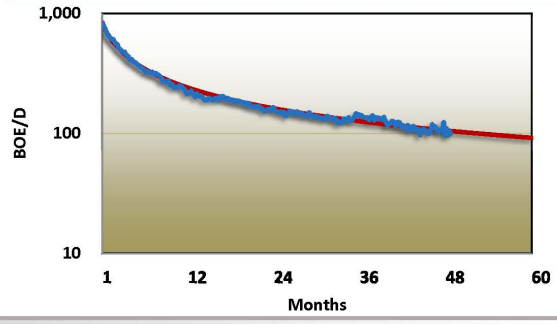
Upper Wolfcamp Type Curves



10,000' Lateral

- EUR: 1,110 MBOE (45% oil)
- 180-day cumulative: 118 MBOE (61% oil)
- 365-day cumulative: 187 MBOE (58% oil)

Normalized production[1]
Type curve



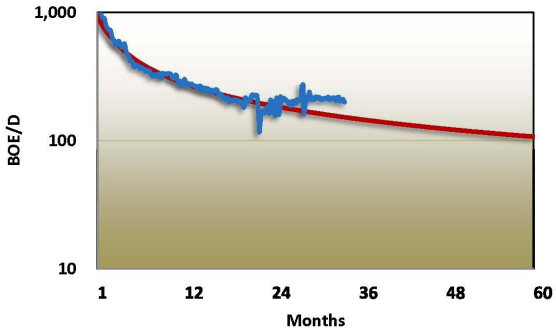
7,500' Lateral

- EUR: 850 MBOE (45% oil)
- 180-day cumulative: 90 MBOE (61% oil)
- 365-day cumulative: 142 MBOE (58% oil)

Normalized production[2]
Type curve

[1] Data includes horizontal wells with lateral lengths >8,500' and 31 stages
[2] Data includes horizontal wells with lateral lengths >6,000' and 24 stages
Note: Production data as of 10/07/16, utilizing 73% residue shrink & 116 Bbl/MMcf yield

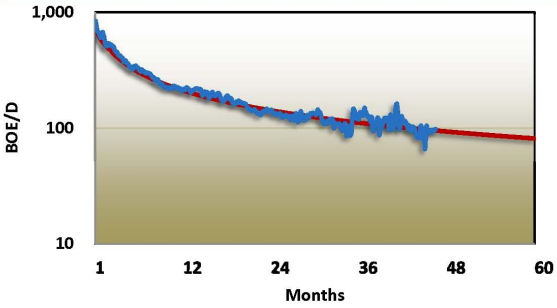
Middle Wolfcamp Type Curves



10,000' Lateral

- EUR: 1,000 MBOE (51% oil)
- 180-day cumulative: 104 MBOE (62% oil)
- 365-day cumulative: 165 MBOE (59% oil)

Normalized production[1]
Type curve



7,500' Lateral

- EUR: 750 MBOE (51% oil)
- 180-day cumulative: 79 MBOE (62% oil)
- 365-day cumulative: 125 MBOE (59% oil)

Normalized production[2]
Type curve

[1] Data includes horizontal wells with lateral lengths >8,500' and 31 stages
[2] Data includes horizontal wells with lateral lengths >6,000' and 24 stages
Note: Production data as of 10/07/16, utilizing 73% residue shrink & 116 Bbl/MMcf yield

2015 & 2016 YTD-Reported Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16
Production	Production (3-Stream)								
	BOE/D	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276
	% oil	51%	46%	45%	45%	47%	48%	46%	46%
Realized Pricing	3-Stream Prices								
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10
Unit Cost Metrics	3-Stream Unit Cost Metrics								
	Lease Operating ($/BOE)	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85
	Midstream ($/BOE)	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22
	G&A ($/BOE)	$5.11	$5.48	$5.56	$6.04	$5.53	$4.63	$4.73	$5.54
	DD&A ($/BOE)	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45

2014 Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	**Production (2-Stream)**					
	BOE/D	**27,041**	**28,653**	**32,970**	**39,722**	**32,134**
	% oil	58%	58%	59%	60%	59%
	Production (3-Stream)					
	BOE/D	**32,358**	**33,829**	**38,798**	**46,379**	**37,882**
	% oil	49%	49%	50%	51%	50%
Realized Pricing	**2-Stream Prices**					
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	3-Stream Prices					
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
Unit Cost Metrics	**2-Stream Unit Cost Metrics**					
	Lease Operating ($/BOE)	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)	$0.35	$0.59	$0.40	$0.50	$0.46
	G&A ($/BOE)	$11.36	$11.34	$8.93	$5.95	$9.04
	DD&A ($/BOE)	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream ($/BOE)	$0.29	$0.50	$0.34	$0.43	$0.39
	G&A ($/BOE)	$9.50	$9.60	$7.59	$5.10	$7.67
	DD&A ($/BOE)	$17.03	$17.23	$17.91	$18.72	$17.83